WORKING PAPER 80-2

A REGIONALIZED ELECTRICITY MODEL: PRELIMINARY ANALYSES

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CHAPTER 1

INTRODUCTION AND OBJECTIVES

It is well recognized that electricity will continue to grow in importance within the Canadian economy. There is general agreement on forecasts which illustrate electricity gradually replacing oil and natural gas as Canada's major energy source.

The growth of the electricity industry in any province or region was in the past essentially related to the rates of economic and population growth. While these are still the primary considerations, a multitude of other factors are highly significant for the examination of provincial, regional or national electricity supply and demand issues. These include: the possibility and probability of substitution out of oil and natural gas, the cost of power in the region and adjoining regions, the potential for interprovincial electricity purchases or interchange, environmental regulations and capital constraints.

As circumstances change, it is difficult enough to analyze the implications for electricity supply or demand in one province, let alone the effects on that province's energy sector as a whole or the implications for the regional or national electricity industry. The complexity of the Canadian electricity industry necessitates a consistent analytical framework to aid in the interpretation of these relationships.

We considered the possibility of constructing a single model system for analyzing issues such as those posed above, but this appeared to be an unusually long-term, high-cost solution to the problem. As such, we commenced a survey of electricity-related models, their reviews, and applications, in search for an analytical framework compatible to our research needs.

On the basis of a number of independent model reviews and assessments we concluded that the Regionalized Electricity Model (REM) developed at the Massachusetts Institute of Technology by Martin L. Baughman, and Paul L. Joskow was the best and most complete model available to examine the interrelationship between energy policies, costs, prices and demands in the electricity industry. The word 'available' is very important for our purposes. We were only interested in a policy analysis tool which could be employed in a 'hands on' fashion. The 'black box' nature of many proprietary models prevented us from obtaining an adequate understanding of their structure, equations, and key coefficients. For this reason, a number of potentially promising models had to be excluded.[1]

Appendix A presents a summary of the conclusions of studies which either used REM for policy analysis or reviewed REM's relative strengths and weaknesses.

Our objectives in this working paper were to:

- describe the Regionalized Electricity Model;
- discuss the alterations we have made to REM;
- conduct several model simulations to illustrate its capability and applicability; and
- delineate possible future areas of research.

Our overall objective in conducting this research is to develop an analytical tool that can be used to evaluate the implications of the many factors which influence the operation and planning of the Canadian electricity industry. Such a framework is not yet available in the Canadian context.

Given these objectives, Chapter 2 contains a description of REM along with a review of major modifications already completed. Chapter 3 summarizes the results of seven simulation experiments. The fourth and final chapter outlines our suggestions for future research with REM.

Footnotes

[1]Two examples were the electricity component of the Data Resources Incorporated Energy Model and the Gordian Associates Incorporated (New York consulting firm) electricity optimization model. The latter firm's model contains generation reliability, dispatch simulation, linear programming optimizer and financial components which can be used to analyze system planning, load management and pricing issues.

CHAPTER 2

MODEL DESCRIPTION

This chapter describes the physical attributes of the Regionalized Electricity Model.[1] It proceeds in varying levels of detail concentrating on those aspects most relevant to this working paper. Both the original configuration of REM and the structural alterations we have undertaken are summarized.[2]

2.1 Structure of the Regionalized Electricity Model[3]

2.1.1 An Overview of Model Design

REM can be capsulized as a dynamic regionalized engineering econometric simulation model of the electricity industry. Its strength originates not from any individual element in isolation, but from the integration of all the major components of the electricity market into a single consistent framework.

REM is <u>not</u> sufficiently detailed and precise to address capacity expansion, operating, or pricing decisions for an <u>individual</u> electric utility. Nevertheless, the model is, in effect, an aggregate version of the utility decision process, dealing with the same type of information that would be used by an individual utility. Accordingly, certain policy related issues affecting the industry as a whole can be effectively approached and analysed.

REM is composed of quantitative descriptions which interact with sets of decision rules that govern the dynamic nature of the model. Electricity suppliers choose a mix of--capacity, generation, transmission, and distribution equipment--to reliably and at least cost meet the electricity needs of their customers. On the other hand, consumers choose among a set of energy input possibilities--coal, oil,

natural gas, and electricity--to meet their needs and maximize their satisfaction within their budget constraints. In both cases decisions are made based upon a set of expectations and goals.

On a less abstract level, REM consists of three basic parts, each of which characterize a certain aspect of the electricity market. These are the supply, demand, and financial/regulatory submodels.

The supply side of REM is a process model. It explicitly sets forth a set of technical possibilities for the supply of electricity. The generation alternatives considered are:

- hydroelectric
- nuclear reactors
- coal-fired thermal
- oil-fired thermal
- natural gas-fired thermal
- internal combustion units

The decision rules take as inputs the characteristics of these different production technologies (expected construction and operating costs, conversion efficiencies, and so on) in combination with the goals of the industry (reliability, minimum cost of operation) to yield an investment or operating decision outcome. The rest of the mathematical structure of the supply submodel reflects past decisions made, such as the mix of technologies chosen, the amount and types of capacity under construction, and the relevant start-up dates. It treats the supply of electricity individually for each of the regions and is structured to reflect specific industry planning and operating techniques.

The demand for electricity is represented as a two-stage decision process. First, the consumer decides on a desired level of energy consumption based on the price of energy, the prices of other goods, and income. The consumer then seeks the specific combination of fuels that will fulfill these requirements at least cost.

The link between the supply and demand sides of the market for electricity is the price of electricity. This price is computed in REM according to the rate-setting practices of electric utility commissions. The price of electricity is set to yield a predetermined rate

of return on the utilities' rate base. Included in the rate base are capital expenditures for generation, transmission, and distribution equipment.

Figure 2.1 is a schematic overview of REM. The interior dotted lines represent the logical flow of information among the central submodels, while the italicized elements outside the model boundary are the exogenous inputs.

A brief explanation of the four principal information flows follows.

- The demand submodel provides the supply submodel with estimates of the sectorial demands for electricity, the sum of which is the total electricity that must be produced during the current period. These demands are also an input to the load prediction module of the supply submodel where they are combined with previous demands in forecasting future demands for electricity.

- The supply submodel, in turn, provides the financial/regulatory submodel with production costs and current capital expenditures. These cost estimates are used in the financial/regulatory submodel to determine the revenue requirements of electric utilities, and the rate base on which the regulated rate of return is to be calculated. The estimate of capital expenditures is also used to determine the total amount of financing required in the current period.

- After computing the total cost of this financing, the financial/regulatory submodel returns an estimate of the capital charge rate to the supply submodel. This is used in the generation expansion module as one of the factors determining the amount and type of capital investment in future time periods.

- Finally, the financial/regulatory submodel determines the sectorial price for electricity and passes those estimates to the demand submodel. The subsequent calculation of current electricity demands begins the next iteration.

As supply responses are the focal point of this study, it is now worthwhile to take a more detailed look at the supply submodel.

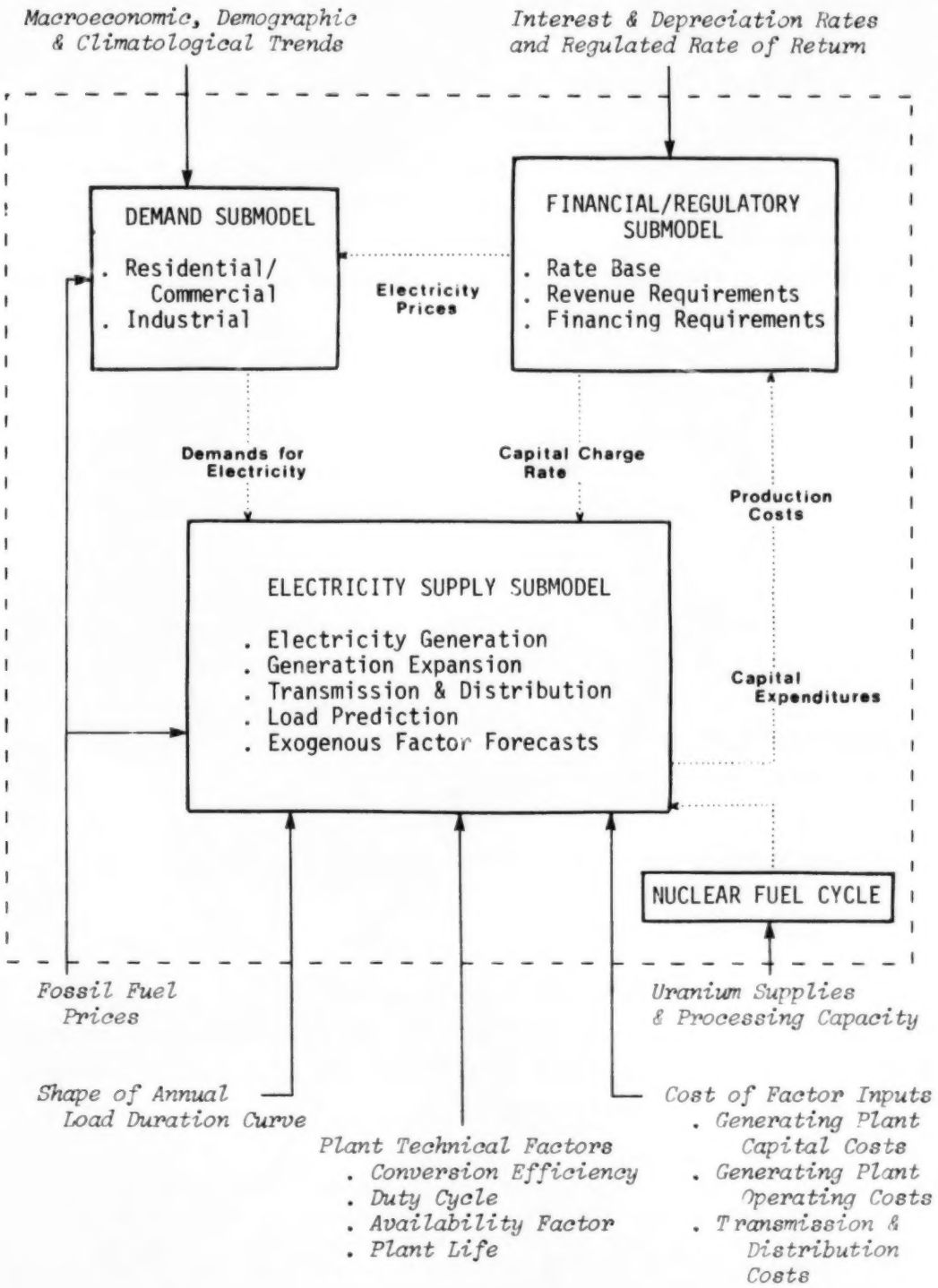


FIGURE 2.1: Schematic Overview of REM.

2.1.2 The Supply Submodel

The supply submodel simulates the two most critical decision processes involved in the operation of an electrical utility system. First, during each time period, electrical utilities have to determine which generating plants should be utilized in order to meet current demands for electricity. The second decision process concerns the investments in new plant and equipment that have to be made in order to meet future demands for electricity.

These behavioural processes are simulated in three primary components within the supply submodel: electricity generation, transmission and distribution, and generation expansion. In addition, the supply submodel contains three auxiliary modules that process input data. These deal with load prediction, exogenous factor forecasts, and the nuclear fuel cycle.

Figure 2.2 outlines the relationships among the components of the supply submodel. The 'inputs' that originate outside the submodel boundary (but that are still endogenous to REM as a whole) are depicted as entering from the top, and the net results of the computations, the 'outputs' transferred to other parts of REM, are shown as exiting from the bottom of that diagram.

Of the three central components, electricity generation and generation expansion are the most important to this working paper.

Electricity generation

The electricity generation component determines the plant utilization rates and production costs incurred in meeting the current demands for electricity. The methodology employed to simulate the decision processes is described as follows:

> At the time production decisions are made all installation (initial investment) costs are sunk costs and only operating costs (fuel plus variable operation and maintenance costs) are used for determining the generating profile. The guiding principle is to use the least operating cost plant as much as possible and, conversely, the highest operating cost as little as possible. In the model each of the plant alternatives is ranked according to its merit of operation corresponding to the level of

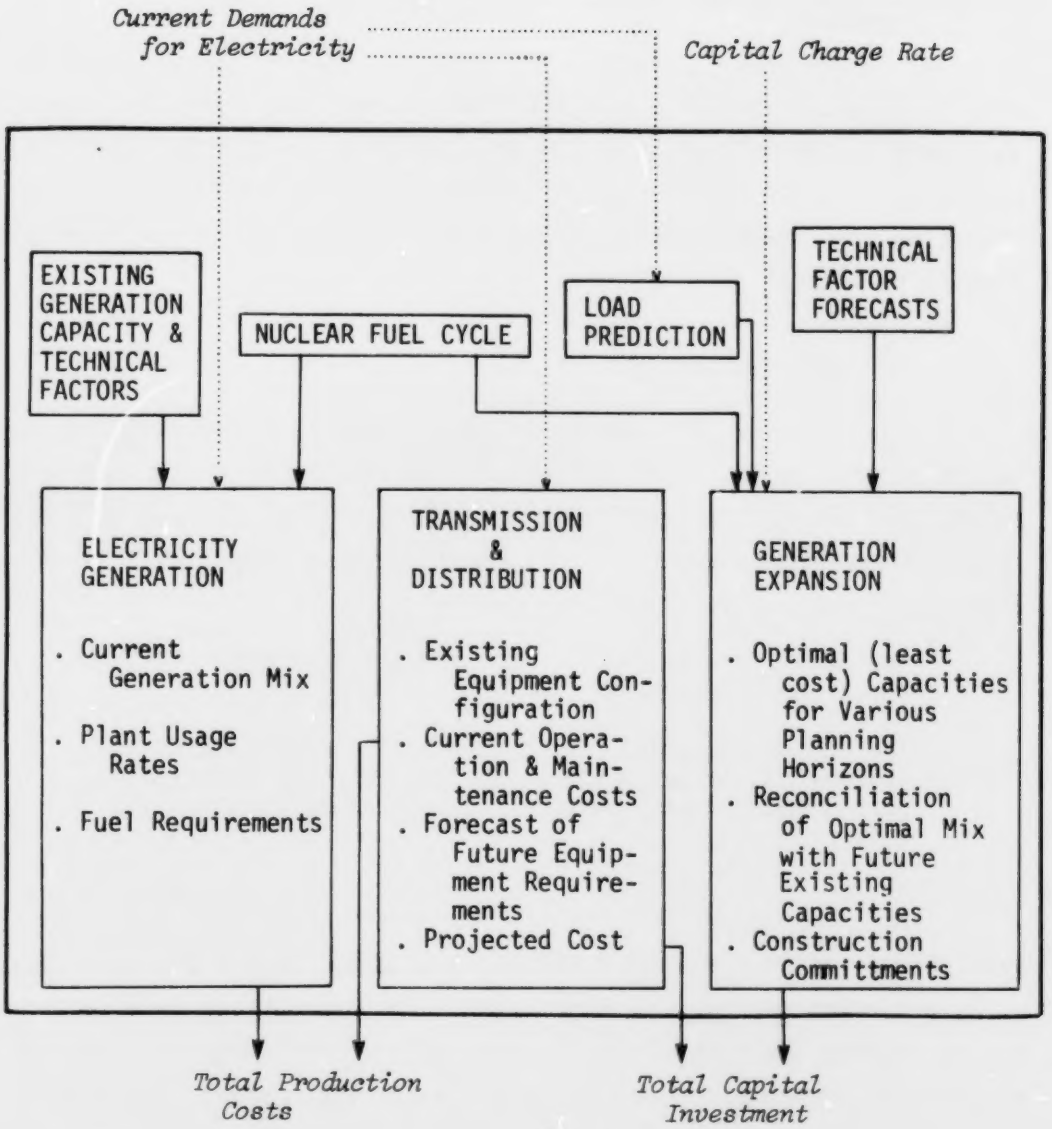

Current Demands for Electricity
Capital Charge Rate
EXISTING GENERATION CAPACITY & TECHNICAL FACTORS
NUCLEAR FUEL CYCLE
LOAD PREDICTION
TECHNICAL FACTOR FORECASTS
ELECTRICITY GENERATION
. Current Generation Mix
. Plant Usage Rates
. Fuel Requirements
TRANSMISSION & DISTRIBUTION
. Existing Equipment Configuration
. Current Operation & Maintenance Costs
. Forecast of Future Equipment Requirements
. Projected Cost
GENERATION EXPANSION
. Optimal (least cost) Capacities for Various Planning Horizons
. Reconciliation of Optimal Mix with Future Existing Capacities
. Construction Committments
Total Production Costs
Total Capital Investment

FIGURE 2.2: Overview of the REM Supply Submodel.

> fuel and operating costs. The total kilowatt hour demand is then generated by consecutively adding the available energy output from each plant type according to its rank in the merit order until the total demand is generated.[4]

By assuming that all of the low-cost baseload plants are always available (after allowing for forced outages) during the peak-load periods, the algorithm in REM represents the most optimistic way of operating the power system. It produces a lower bound estimate of production costs.[5]

Generation expansion

The function of the generation expansion component is to determine the capital investments necessary to bring the appropriate amount and mix of new generating capacity on-line in time to meet future electricity demands. This objective is accomplished in two stages.

- The ideal 'start-from scratch' mix of generation to the end of the planning horizon is computed.
- The method by which the system will move towards the optimum is determined, given the existing capacities, past construction commitments, and capacities due for retirement.

In calculating the 'start-from-scratch' optimum capacities, average generation costs at various plant usage levels are estimated using projected capital and fuel costs. The appropriate intersection points between the cost curves so derived are determined in order to provide the 'envelope' of the optimum (least-cost) curve. The optimum plant type choices together with the range of usage over which they are the optimum choice are projected onto a load duration curve, from which plant types are assigned the appropriate fraction of peak-load requirements. Figure 2.3 provides a graphical summary of this procedure with the least-cost envelope denoted by the heavily shaded line.

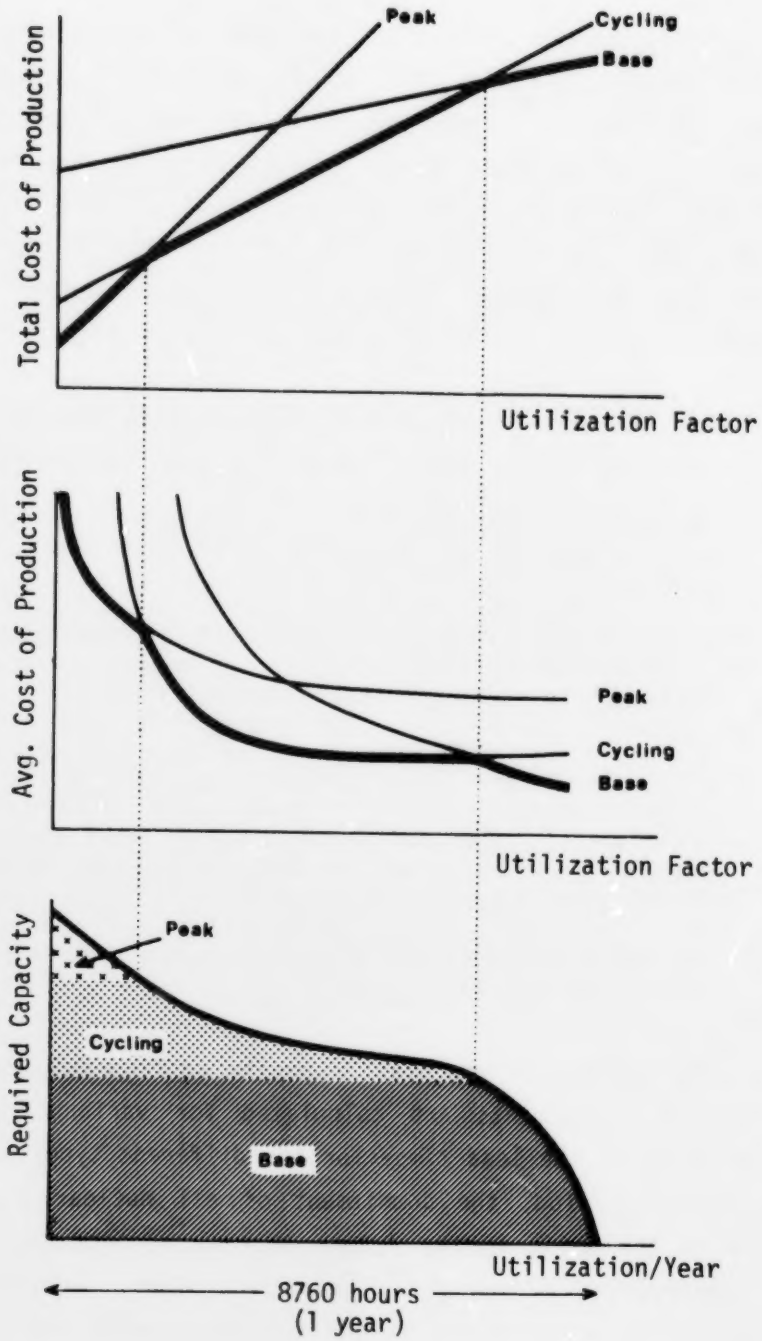


FIGURE 2.3: Simplified Presentation of Optimization Strategy.

These optimum projections are then reconciled with known to be existing future capacities in order to determine the present required capital investments. More specifically, hydro capacity is first subtracted from the peak, then the plant alternatives that are underbuilt are planned in proportion to the extent they are lower than optimum. When the existing capacity of a particular type of plant is greater than the optimum, the excess is used to reduce the need for additional capacity in other types of plants higher in the merit ordering.

For additional new capacity of a specific type to be committed in a given region by the model it must meet four conditions:[6]

1. It must be on the minimum cost production profile when all plant types of equal or lesser lead time are considered.

2. Existing and already planned plant of the type under consideration must be less than the amount calculated as 'optimal' in the ideal static configuration.

3. The new plant, when added to all other plant types to be available in the planning year (that is, existing and planned capacity of all types when accounting for retirements), must not cause total planned capacity to exceed total required to meet forecasted peak when allowing for a margin of reserve.

4. The new plant addition must not exceed any exogenously imposed build limits.

The optimum future plant capacity configuration and resulting construction commitments are calculated for various time intervals corresponding to the lead times for the different types of facilities. In each time period, the commitment of all nuclear plant types is decided to the point in the future that represents the nuclear lead time requirement (10 years). The fossil plant commitments are also decided to the point in the future that represents their construction lead time (5 years). Internal combustion turbines require the least lead time (2.5 years) and are implemented to take up the residual in the system.

2.2 Modifications to REM

Before even the most preliminary application of REM to the Canadian situation is undertaken several structural changes are necessary. These are currently at various stages of completion; some directly concern this working paper while others do not. Figure 2.4 depicts the CERI 'working paper' version of REM, which can be compared to the 'acquired' version presented in Figure 2.1. The major alterations and simplifications are outlined below.

From the outset, the characteristic that made REM an attractive modelling approach was its ability to simulate the electricity sector in individual regions and to aggregate nationally. Only in such a manner could broad policy analysis be embarked upon in a country as inherently diverse as Canada. REM was originally designed to simulate nine U.S. census regions. The CERI version now operates on ten separate regions, which will correspond ultimately to the individual provinces.[7]

As REM was initially acquired to investigate supply side responses, at this early stage in its 'Canadianization' we were not prepared to invest the time necessary to re-specify and re-estimate the parameters in the demand equations. For this reason, the demand calculations were divorced from the REM framework as we opted to stipulate growth rates outside of REM's boundary.

Due to political preferences, the possibility of light water reactors entering the Canadian generation mix in the foreseeable future is negligible. This fact necessitated the curtailment of that possibility, on other than economic grounds. Thus, light water reactors in our version of REM are artificially restricted from the feasible plant type options.[8] However, a pressurized heavy water reactor (CANDU) is incorporated to reflect the Canadian context.[9] It is selected for the current generation mix and expansion planning decisions on the basis of capital cost, operations and maintenance costs, and efficiency criteria, as are the conventional thermal units.

These are the structural modifications to this point in time, some of which we plan to improve upon in the near future. For a longer term perspective of CERI objectives with respect to REM refer to Chapter 4. The next chapter provides an insight into the type of analysis to which REM is amenable.

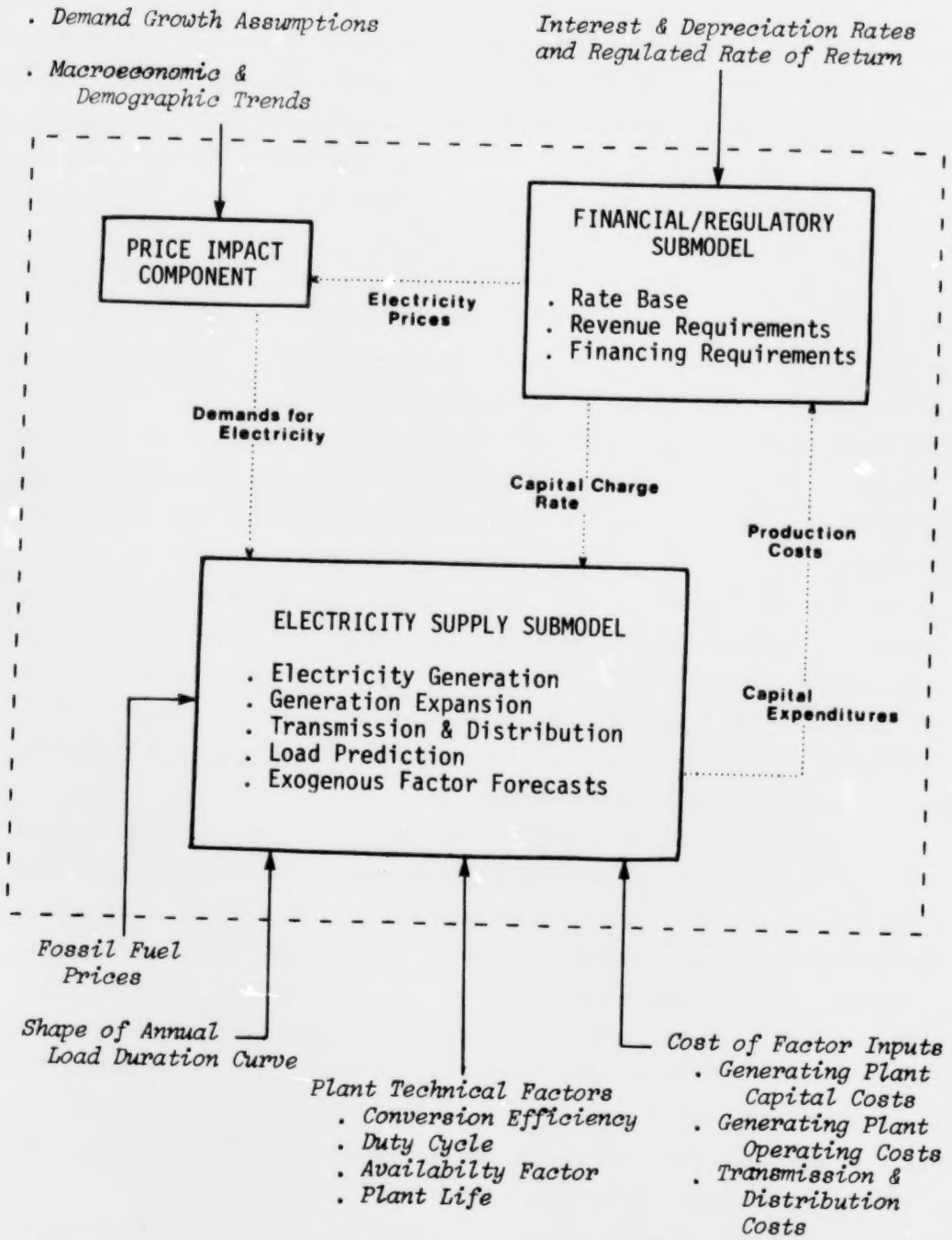


FIGURE 2.4: Schematic Overview of the Current (February 1980) CERI Version of REM.

Footnotes

[1]For the reader interested in the chronological evolution of REM, development began at the MIT Energy Laboratory under the auspices of Martin L. Baughman and Paul L. Joskow in response to the general concern over future energy supplies in the early seventies. Since then, the focal point of the research has moved, with Dr. Baughman, to the Centre for Energy Studies, University of Texas, at Austin.

Baughman and Joskow's initial paper (1974) specifically concerning REM reviewed the theoretical bases for electrical industry planning and operational decisions and unveiled how the demand and supply sides of the market could be interconnected in a modelling framework. A refined set of derived demand functions for energy in the residential/commercial and industrial sector were subsequently specified and estimated by Baughman and Joskow (1974), and Baughman and Zerhoot (1975), respectively. A financial/regulatory mechanism, linking the REM demand and supply sectors through price interactions, was described by Kamat, Baughman and Joskow (1975). A comprehensive transmission and distribution module, for eventual inclusion in the supply submodel, was econometrically estimated by Baughman and Bottaro (1975).

At this point, the majority of the development work was completed and the focus of research turned to policy analysis; the original purpose of the tool. Supplementary to specific policy related papers, several overviews of the electricity industry as a whole have appeared. A recent book (Baughman, Joskow and Kamat, 1979) contains the most inclusive documentation of all aspects of the 'current' working version of REM. As implied, the model continues to undergo refinement.

[2]The initial version of REM that the Institute acquired was almost identical to the 'locked-up' version upon which the MIT Model Assessment Group conducted their analysis. (May 1978).

[3]Much of the description in 2.1.1 and 2.1.2 draws upon the original articles authored by REM's developers.

[4]Paul L. Joskow and Martin L. Baughman, "The Future of the U.S. Nuclear Energy Industry," Bell Journal of Economics (Spring, 1976): p.12.

[5]A quote from the MIT Model Assessment Group (p. 3-55) serves to qualify the methodology invoked to determine the current generation mix:

> It is worth noting that the generation simulators used by electric utilities are considerably more sophisticated than the electricity generation model in REM. The utility models commonly employ probabilistic simulation, incorporate many more types of generating plants, and take into account seasonal factors. The use of an annual load duration curve in REM,

although a reasonable simplifying assumption for some purposes, restricts the applicability of the REM results. The utilization of peaking and cycling plants follows different patterns at different times of the year. Under some circumstances, this could significantly affect production costs. While the use of seasonal load duration curves would certainly provide a better representation of the real situation, it is not clear whether this factor is crucial to the types of issues being addressed by REM.

[6]Martin L. Baughman, Paul L. Joskow, and Dilip P. Kamat, Electric Power in the United States: Models and Policy Analysis (Cambridge, Mass.: MIT Press, 1979): p. 25.

[7]Unfortunately the REM computer code is quite 'application specific' and a change to the number of regions simulated is not easily implemented. It is our desire to be able to specify at run time the number of regions modelled. Such an option would facilitate the examination of prospective grid systems.

[8]This is unfortunate since the original nuclear module encompasses all the relevant aspects of nuclear fuel economics, like reprocessing and plutonium management. More specifically, four distinct nuclear plant types are modelled:

- light water uranium reactors
- plutonium recycle reactors
- high temperature gas reactors
- liquid metal fast breeder reactors.

[9]Additional plant types will be made operational as work progresses, see Chapter 4 for details.

CHAPTER 3

SIMULATION EXPERIMENTS

In order to illustrate some of the capabilities of REM the results of a base case simulation and of seven experimental analyses are presented and discussed in this chapter. The seven 'experiments' were based on alternative scenarios of cost or policy changes which could influence the electricity industry.

It should be made clear at the outset that all 'results' described herein are strictly for illustrative purposes. We have made the following simplifying assumptions to ensure a clear understanding of the model's operation:

- The model is operated with only one region. This is a limiting assumption since the model's ultimate power and usefulness rests on its aggregative ability and capability of analysis from a national viewpoint. Nevertheless, the model operates in an identical fashion for every region and our main interest was to depict the response of expansion plan and operation supply-side components to various shocks.

- The data inputs, while realistic in nature, are not meant to be representative in whole or in part of any particular North American electric utility. The purpose for this was to avoid the preconceptions that would arise if actual data from a utility or region were used.

- To further isolate the operation of the supply-side component of the model, the own price elasticity of electricity demand in the price impact component of the model was set at zero.

- We have ignored, for purposes of this working paper, retail transmission and distribution, and have concentrated on bulk power generation and associated bulk transmission costs and issues.

- In REM the treatment of hydroelectric generating stations is exogenous to model operation. We have made the assumption of a relatively mature hydro system in our hypothetical region. This suggests that only a few small exogenously specified increases in hydro capacity will occur over the period 1980 to 2000.

Simulation results are illustrated in this paper in five year increments between the years 1985 and 2000 inclusive. Energy demand, peak power demand, bulk electricity cost (current dollars), and reserve margin levels are summarized in tables while installed capacity and energy generated by plant type are depicted in a bar chart format.

The energy demands are exogenous to these simulations. The peak power demands, reserve margins, installed capacity and energy generated by plant type are outputs of the supply submodel. The supply submodel of REM also outputs effective capacity, optimum future capacity, and usage factor by plant type. While this additional information is not presented in the figures, it is sometimes referred to in the supporting text to the simulations. Due to our concentration on the supply side component of REM, the average bulk power electricity cost is the only output of the financial-regulatory subroutine which is presented.

3.1 The Base Case

The Regionalized Electricity Model requires a large amount of historical data input which reflects electricity expansion plans, population figures, costs, and so on, for each region. The history of our hypothetical region is not dissimilar to that of many other North American electric utilities. The 1950s and 1960s were characterized by relatively high demand growth rates and capacity expansion. The early seventies saw the beginning of rapid factor cost increases and somewhat dampened demand growth rates.

The base case simulation is described in two sections. The first section presents the 1980 input data and predicted generation configuration, while the second contains an account of the base case forecasts. Appendix B provides a more complete summary of the data from which we derived the base case.

3.1.1 Base Case - 1980

Hypothetical Region

Demographic:	Population	3.8 million
	Area	100,000 square miles
Electricity Demand:	Residential/Commercial	18,952 GW.h
	Industrial	17,502 GW.h
	Total Energy Demand	36,454 GW.h
	Peak Power Demand	6,629 MW
	Load Curve Usage Factor	62.8%

Generation Option Costs:

	New Plant Capital Cost (1980 $/kW)	Fuel and Operations and Maintenance Cost (1980 mills/kW.h)
Hydroelectric	860	0.3
Coal-fired thermal	560	11.5
Gas-fired thermal	320	21.6
Oil-fired thermal	400	36.7
Nuclear	990	3.8
Internal combustion	220	59.3

Existing Generation Mix:

	Installed Capacity (MW)	Electrical Generation (GW.h)
Hydroelectric	2,575	14,724
Coal-fired thermal	2,809	19,264
Gas-fired thermal	72	473
Oil-fired thermal	1,204	1,874
Internal combustion	1,614	119
Total	8,274	36,454

Reserves Based on Installed Capacity	24.8%
Average Bulk Power Cost	23.6 mills/kW.h

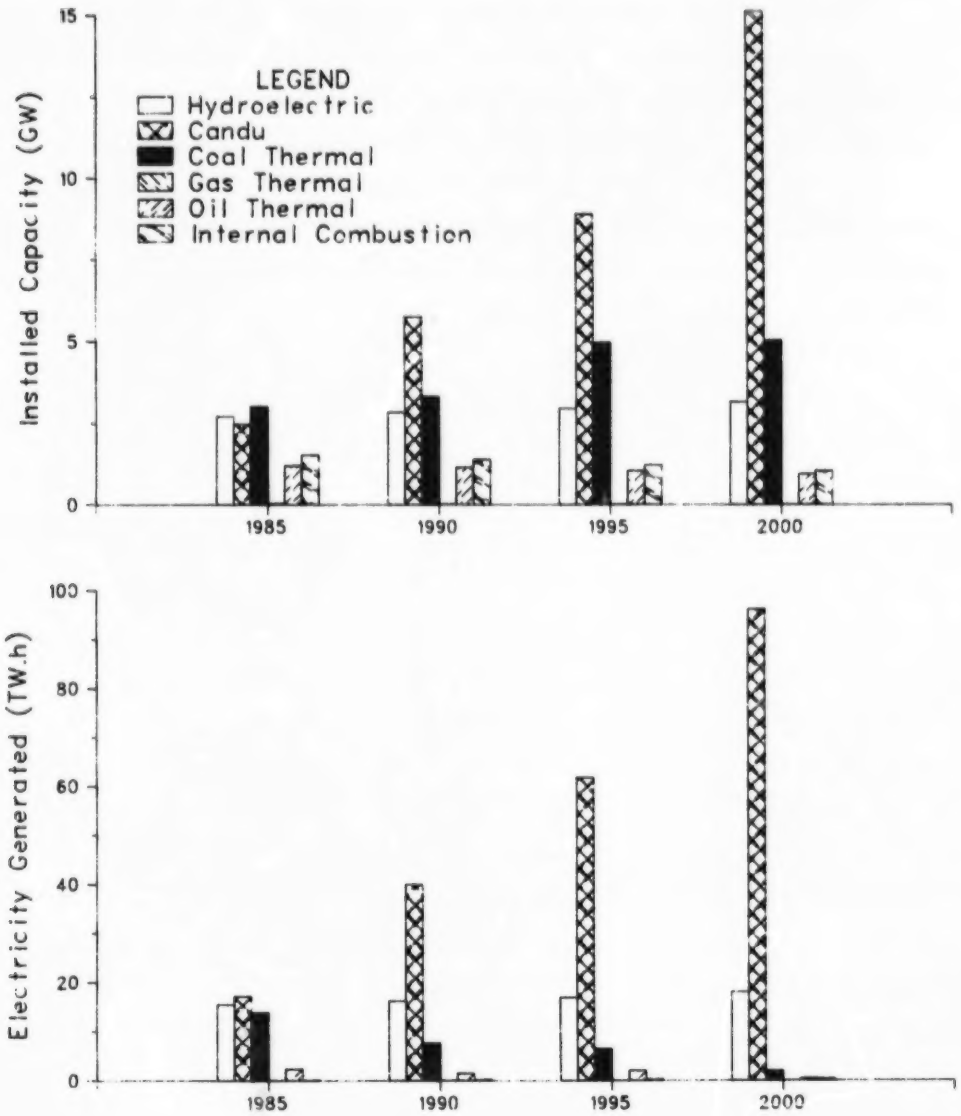
The utility or utilities in this region are characterized by a varied and well balanced mix of generating plant types. The vintages of the existing generating units are highly diverse. In the five years since 1975 the electricity industry has constructed about 500 MW of coal-fired capacity and 175 MW of hydroelectric. Oil-fired capacity has remained essentially constant while installed gas-fired steam and internal combustion (which includes gas turbines) capacity is lower in 1980 than it was in 1975 due to retirement. In 1975, nuclear generating stations entered the industry's system expansion plans and in 1980 they are within two years of start-up. The decision to build nuclear was largely influenced by the dramatic increase in fossil fuel prices since 1973 (350, 600 and 200 percent for oil, gas and coal respectively).

3.1.2 Base Case 1980-2000

The base case projections are summarized in Figure 3.1. It can be observed that energy demanded, peak load and bulk electricity cost are generally projected to grow smoothly through time. The electricity industry commences nuclear generation in 1982 and the comparative advantage of the nuclear option result in the rapid growth of that capacity type. Coal-fired capacity, which fulfilled (with hydro) the baseload requirements until the introduction of nuclear, also grows but at a much slower and more sporadic rate. Its role largely changes to one of filling intermediate or cycling capacity needs. As such, installed coal-fired capacity peaks at approximately 5400 MW in 1996 and thereafter begins to decline. The last new oil-fired unit in this hypothetical region was built in 1977 and installed capacity begins to decline by the late eighties as older vintage units are retired. Similarly, gas fired steam capacity, which was never abundant prior to 1980 enters a steady decline and disappears by 1994. The eventual disappearance of these two fossil-fuelled capacity types is obviously due to past and forecast fuel price increases. Total installed internal combustion and gas turbine capacity declines gradually over time as gas and oil-fired steam units are being forced up the dispatch curve from cycling to peaking unit status.[1]

FIGURE 3.1: Summary of Base Case Results (levels).

	1985	1990	1995	2000
Electric Energy Demanded (TW.h)	49	65	87	117
Peak Power Demand (GW)	9	12	16	21
Cost of Electricity (mills/kW.h)	33	48	71	107
Reserves Based on Installed Capacity (%)	23	22	20	19



The electricity generated by plant type also reveals an overpowering nuclear future. In 1980, coal-fired and hydro plants shared all of the baseload capacity. By 1985 nuclear is responsible for 35 percent of total generation in the base case. In 1990, nuclear and hydro are meeting all base load requirements.[2] Beyond 1990, nuclear is sufficiently inexpensive relative to the next best option that it begins to make inroads into coal's intermediate capacity domain. In other words, nuclear capacity could be operated at less than full capacity (ie. 80 percent capacity factor) and still be the economic alternative. The result is that by the year 2000 nuclear and hydro together produce 97.7 percent of total electricity generated in the region. All fossil fuelled capacity types are therefore eventually relegated to a peaking or cold reserve capacity designation.

The results are notable even though this is only a hypothetical base case because, if the assumed capital, fuel and other costs are generally realistic, the economic superiority of the nuclear option is clear.

3.2 The Sensitivity Analyses

The reader should note that our objective is to illustrate the 'types' of analysis possible with REM rather than delve into all possible scenarios. Moreover, in reality one may not expect such severe 'shocks' as those that we imposed in the simulations described below. The simulations were designed to demonstrate the range of response rather than to reflect most probable futures.

For the following seven types of sensitivity analysis the nature of the stimulus, possible real-life sources, and the impact in relation to the base case is briefly described. Each is then summarized in tabular and graphic form; the bar charts indicating level differences from the base case. All costs presented in the tables and discussed in the text are in current (escalated) dollars.

3.2.1 Type 1, Electricity Demand

Stimulus:

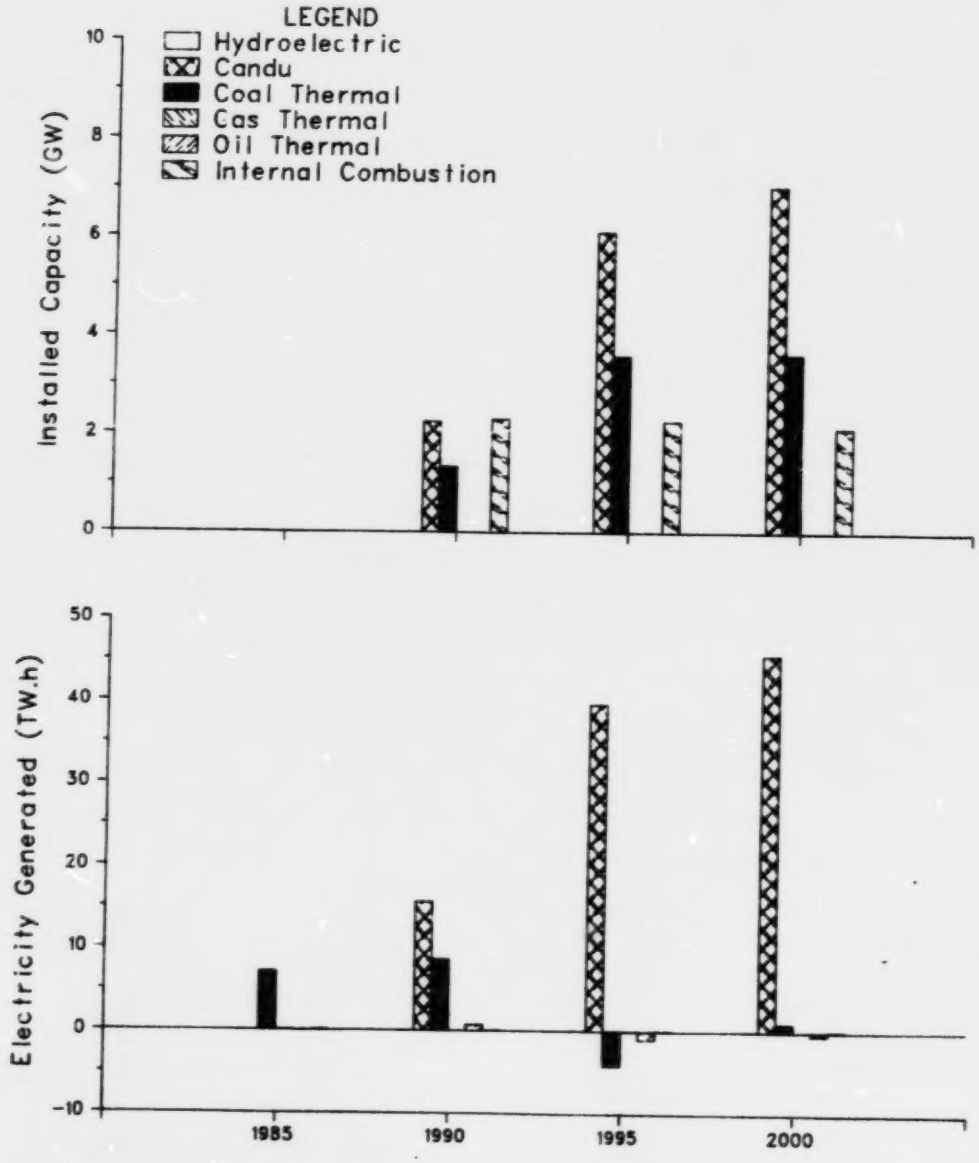
This first example is designed to illustrate the model's capability to respond to demand disturbances. In this case we postulated a scenario wherein electricity demand growth rates undergo a significant and relatively sudden increase. The impetus could come from one or more sources, such as: an accelerated substitution of electricity for other fuel sources, a rapid population increase, or the unexpected entry of a new large industrial load.

More specifically, overall electricity demand which was rising steadily at 6 percent annually in the base case was shocked in the following manner:

Time Period	Demand Growth Rate	Time Period	Demand Growth Rate
1966-1980	6%	1987	11%
1981	7%	1988	10%
1982	8%	1989	9%
1983	9%	1990	8%
1984	10%	1991	7%
1985	11%	1992-2000	6%
1986	12%		

FIGURE 3.2: Summary of Sensitivity Results – Type 1.
(bar graphs indicate level differences from base case)

	1985	1990	1995	2000
Electric Energy Demanded (TW.h)	56	90	122	163
Peak Power Demand (GW)	10	16	22	30
Cost of Electricity (mills/kW.h)	33	55	87	114
Reserves Base on Installed Capacity (%)	7	24	40	28



Impact:

The effect of this demand growth scenario on the region's electricity system generation expansion plan is as follows:

- The initial unforeseen change in 1981 in the demand growth rate (from 6 to 7 percent) would cause, given a trend line projection, slightly greater baseload capacity levels six years hence (the second half of 1986). Thus a small amount of this type of capacity (five year construction lead time) is built into the system expansion plan.

- However, demand growth rate increases continue and by 1983, reserve levels (17 percent of installed capacity) begin to fall below the planning level of 20 percent. It is now apparent that additional generation capacity is required in the near term future. Unfortunately the generating plants with the shortest construction lead time (two and one half years) are internal combustion or gas turbine units. Thus, the region's electricity system plans for the construction of substantial amounts of this type of capacity as soon as possible (first half of 1986).

- By 1985, system reserve levels are near 7 percent. As can be seen in Figure 3.2, while 1985 installed capacity levels are identical with the base case, considerably more energy is being generated from coal. In fact, coal, nuclear and hydro units are operating at their maximum usage factors.

- Commencing in 1986, new capacity in the form of internal combustion and nuclear units comes in-service as the system begins to adapt to the higher demand growth rates. Unfortunately demand growth rates begin to fall in 1987. Thus, as the region is constructing more coal, nuclear and internal combustion or gas turbine units in the late 1980s, an opposite problem surfaces.

- If there is an unforeseen drop in demand growth rates as is postulated to occur in this scenario in the 1987 to 1992 period, the system begins to show signs of being overbuilt by 1990. This phenomenon crests in 1994 with 40 percent system reserve capacity.

- By 2000, the system has largely equilibriated itself. Electricity demands are approximately 40 percent higher than in the base case and yet average bulk power electricity cost is only 6.5 percent higher. There is still some excess capacity on the system but this would be gradually removed over time provided there were no further demand growth 'shocks' in the region.

3.2.2 Type 2, Fossil Fuel Prices

Stimulus:

In this case the price of a major fossil fuel (coal) input into electricity generation was stipulated to increase less rapidly than in the base case. Such a situation could be brought about by a variety of reasons--subsidies to coal transportation, technological advances in production, or the discovery of significant, readily accessible new reserves. More specifically, the price of coal was decreased by 50 percent in 1980 and in the years following from the levels utilized in the base case.

Impact:

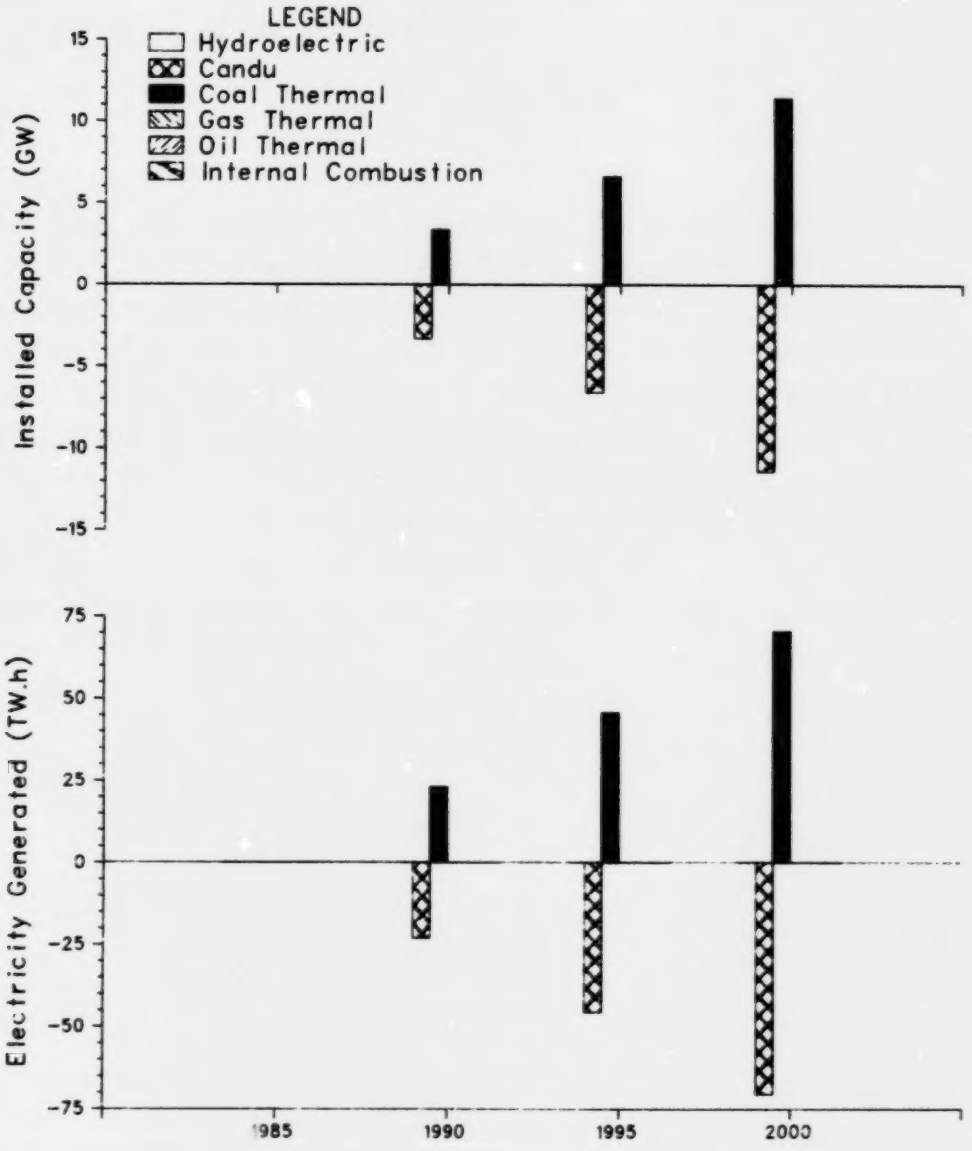
In this scenario, the coal-fired alternative becomes more attractive given the significantly lower operating costs, but the timing of the expansion plan changes is of primary interest.

From 1980-84 the cost of power is less than in the base case but no increase in electricity generation is forthcoming from coal plants. The reasons are twofold: in 1980-81 (before nuclear units were introduced) coal was already being operated at its maximum usage factor; in the 1982-85 period the nuclear alternative was still the preferred operating choice as dictated by its still lower operating costs relative to the coal-fired generation.

However, system expansion plans began to favour coal as early as 1981 as it becomes the preferred construction option on a Net Present Value basis. Thus, beginning in 1986 and through to 1994 more coal, and proportionally less nuclear, is built relative to the base case. In 1994, though, nuclear generation once again becomes economic. In the year 2000 new nuclear units are commissioned for the first time since 1985.

FIGURE 3.3: Summary of Sensitivity Results – Type 2.
(bar graphs indicate level differences from base case)

	1985	1990	1995	2000
Electric Energy Demanded (TW.h)	49	65	87	117
Peak Power Demand (GW)	9	12	16	21
Cost of Electricity (mills/kW.h)	31	45	67	103
Reserves Based on Installed Capacity (%)	23	22	20	19



3.2.3 Type 3, Capital Costs

Stimulus:

In this case, the capital cost of a generation plant type (CANDU) was increased relative to the base case assumptions. The possible sources of such an increase are increased environmental safeguards, siting restrictions, and higher forecast decommissioning costs.

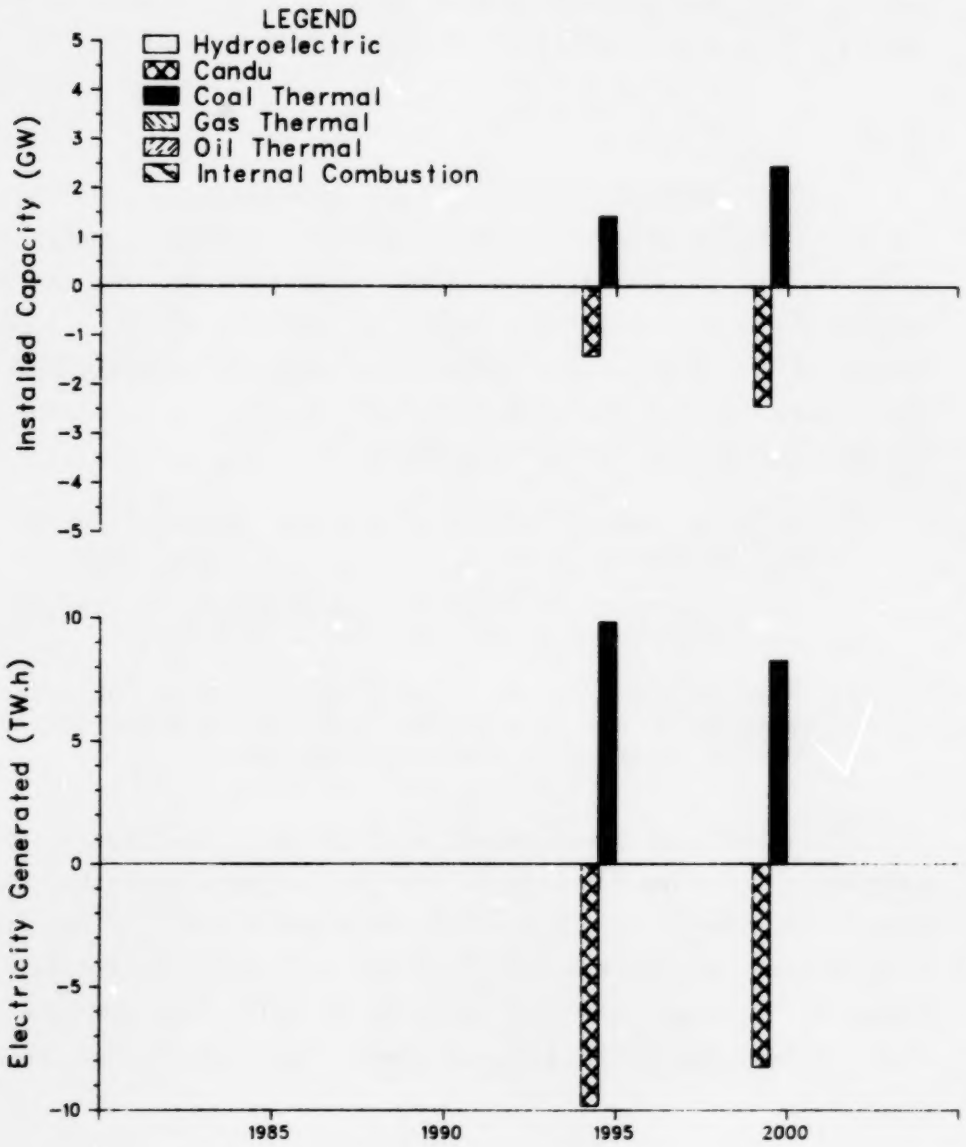
A gradual increase in CANDU capital costs was initiated over the period 1982-87, rising to and remaining at 25 percent above the base case levels in 1987 and thereafter.

Impact:

The utilities' first response is a movement away from nuclear in the 1989 expansion plans, with coal being the preferred alternative. Thus, by the latter half of 1994 coal-fired capacity is being constructed when it was not in the base case. Naturally enough, as illustrated in Figure 3.4, more of the system's total energy needs are met by coal-fired generation than was the situation in the base case. However, by 1997 nuclear units are again competitive with conventional thermal. The system exits the century with a well balanced mix of nuclear and coal generation. The economic choice between the two alternatives is much closer under these assumptions than in the base case.

FIGURE 3.4: Summary of Sensitivity Results – Type 3.
(bar graphs indicate level differences from base case)

	1985	1990	1995	2000
Electric Energy Demanded (TW.h)	49	65	87	117
Peak Power Demand (GW)	9	12	16	21
Cost of Electricity (mills/kW.h)	34	52	77	115
Reserves Based on Installed Capacity (%)	23	22	20	19



3.2.4 Type 4, System Load Factor

Stimulus:

This example concerns an increase in the system's annual load factor.[3] Such a situation could arise as a result of many circumstances. These include: peak-load pricing, seasonal pricing, load management, and industrial co-generation.

The load curve usage factor for all years was 0.638 in the base case. This was increased progressively to 0.750 between 1977-87 and maintained at that level for the duration of this simulation.

Impact:

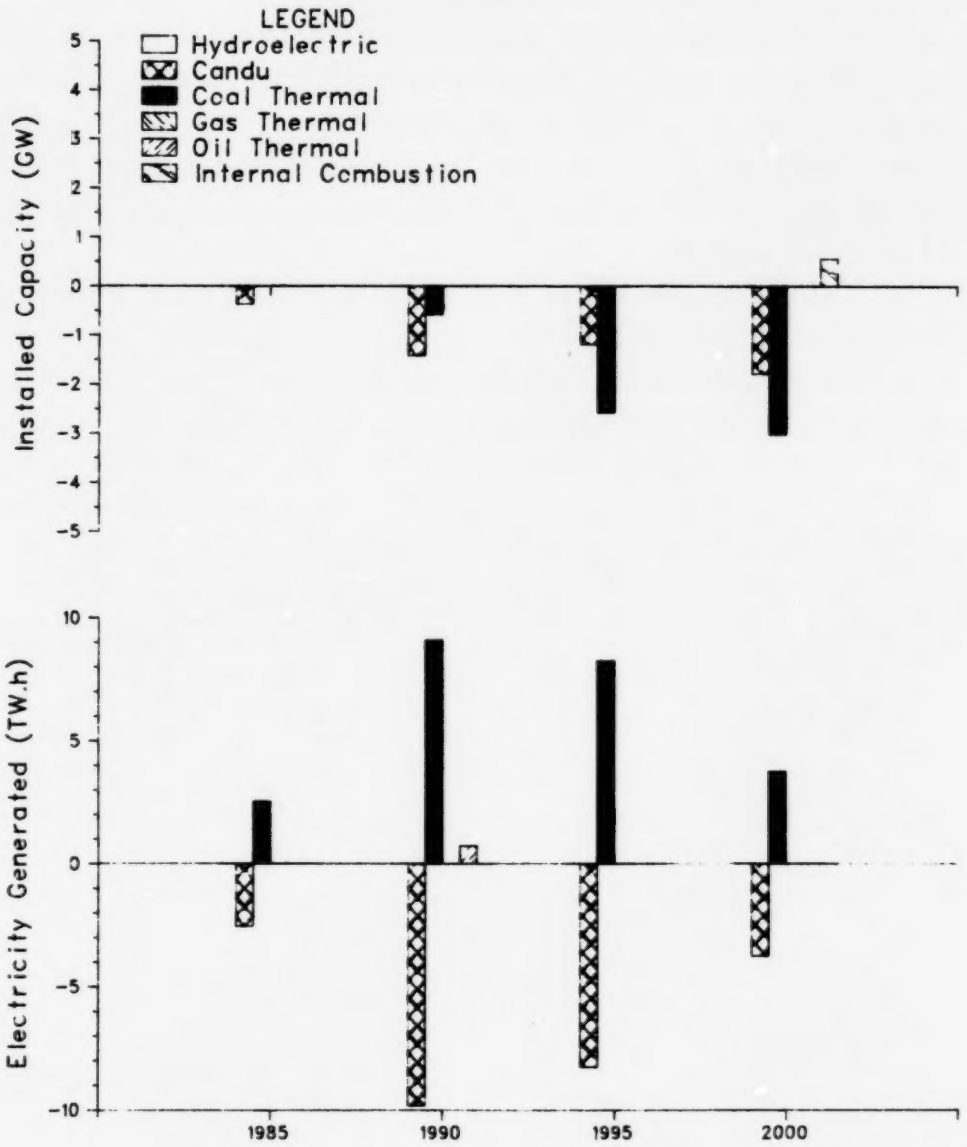
The intuitive result of an increased load factor is a reduction in the amount of peaking capacity required. However in our scenario, the increase in load factor is so rapid as to cause reserve margins to become very high (around 40 percent) in the early 1980s before system planners can effectively postpone capacity additions. The result is that the first type of capacity to be deferred are baseload nuclear units. This happens because:

- Deferring nuclear units offers the greatest capital cost savings.
- Reserve margins are high even as a percentage of peak power demand so baseload units can be postponed.
- 'Peaking' capacity as a percentage of total installed capacity is only 15 percent in 1984 thus leaving little room for deferment of that capacity type.

In 1988 peak power demand is 16 percent lower than in the base case while installed capacity is only 9.5 percent lower than the base case. The reserve margin is still relatively high (32 percent) and only nuclear capacity has been deferred. In 1989 the regional system begins to introduce less coal capacity as well. By 1991 the excess capacity has dropped to a level almost identical to the base case

FIGURE 3 5: Summary of Sensitivity Results – Type 4.
(bar graphs indicate level differences from base case)

	1985	1990	1995	2000
Electric Energy Demanded (TW.h)	49	65	87	117
Peak Power Demand (GW)	8	10	13	18
Cost of Electricity (mills/kW.h)	32	44	63	96
Reserves Based on Installed Capacity (%)	37	24	15	18



(22 versus 21 percent) and the total generation plant usage factor is 61.2 percent versus the base case usage factor of 51.8 percent. This efficient use of capacity results in an averge bulk power cost which is about 10 percent lower than in the base run.

The load factor level has stabilized by 1987. Given that the trend toward higher regional system load factors had ended, the system was in a position by the early 1990s to have postponed or cancelled too much baseload capacity. The results were reserve margins (14 - 17 percent) that were slightly below the planning requirement of 20 percent. Therefore, the system was required to build peaking capacity (commencing in 1996) to provide the additional reserve. The net result in the year 2000, as illustrated in Figure 3.5, is internal combustion capacity levels which are about 50 percent higher than in the base case. This 50 percent figure represents an additional 550 MW of peaking capacity.

While the results of this scenario indicate that higher system load factors could lead to the counter-intuitive situation of greater requirements for peaking capacity, it does also illustrate the potential for cost savings from higher system load factors.

3.2.5 Type 5, Financing Costs

Stimulus:

In this case, the cost of financing future expansion is deemed to rise above the rates specified in the base case. Such a situation could arise from a higher allowed rate of return or a general increase in interest costs, for example.

The financial parameters were changed as follows:

	Base Case	Shock Case
Interest rate on new debt issue	8.5%	9.5%
Divided rate on new preferred stock	8.7%	10.0%
Allowed rate of return on equity	14.0%	16.0%

Impact:

The major consequence is the effect on the cost of electricity, which in turn serves to increase the revenue requirements as indicated below.

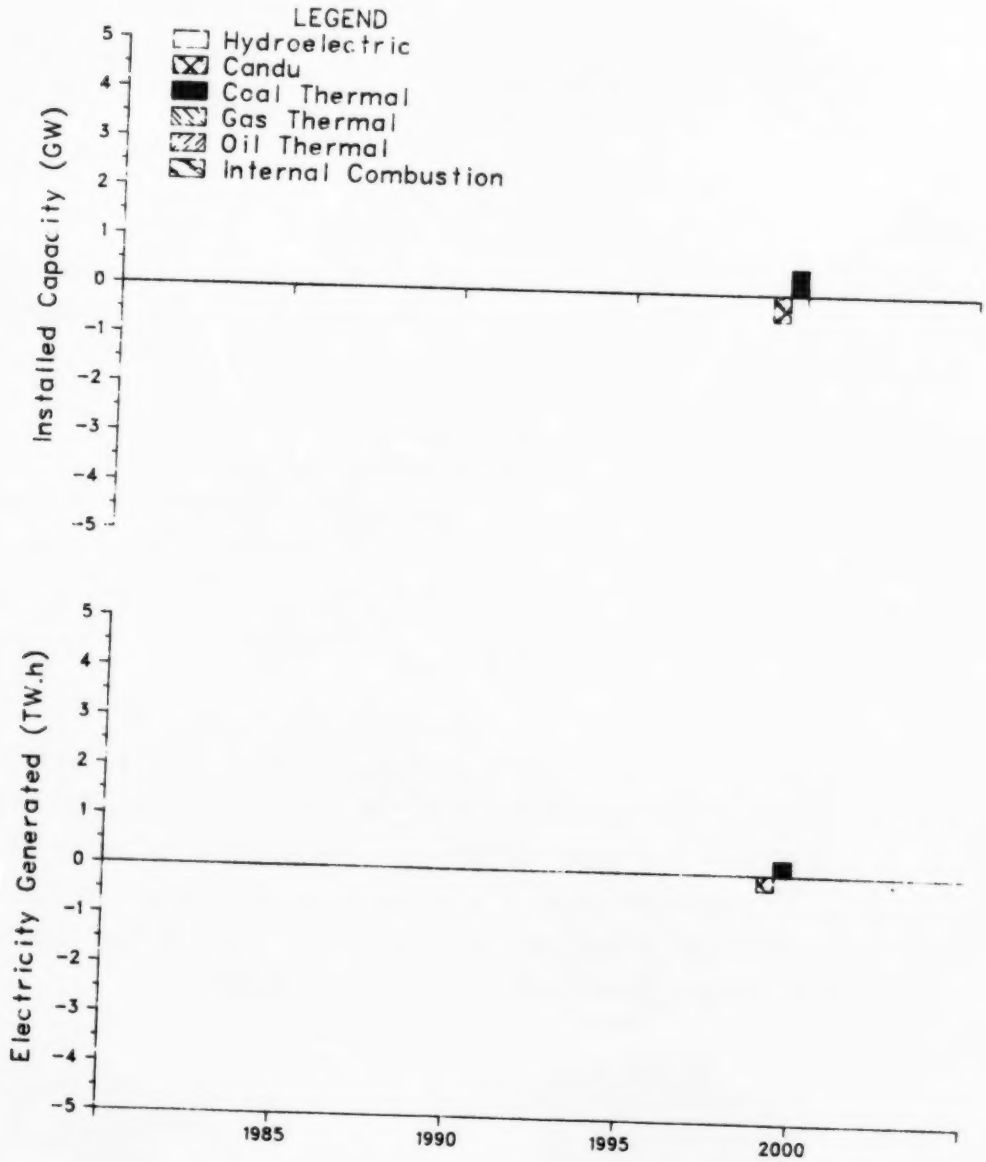
Revenue Requirements
(billions of current dollars)

	1980	1990	2000
Base Case	0.86	3.15	12.46
Type 5 Sensitivity	0.94	3.47	13.66

As portrayed in Figure 3.6, there is virtually no effect on reserve margins or the generation mix. Between the years 1997 to 2000 slightly more coal and less nuclear was installed in relation to the base case, but the 1997 expansion plans were identical. We conclude that it would take a substantially greater boost in the financial parameters to induce significant long term consequences.

FIGURE 3.6 Summary of Sensitivity Results – Type 5.
(bar graphs indicate level differences from base case)

	1985	1990	1995	2000
Electric Energy Demanded (TW.h)	49	65	87	117
Peak Power Demand (GW)	9	12	16	21
Cost of Electricity (mills/kW.h)	36	53	78	117
Reserves Based on Installed Capacity (%)	23	22	20	19



3.2.6 Type 6, Nuclear Moratorium

Stimulus:

In this example, we speculated that a nuclear moratorium was 'announced' in 1977 to take effect in 1983.

Impact:

The expected effect was observed in the generation mix; with the nuclear alternative eliminated, the coal plant type dominated the expansion horizon. The cost implications are again substantial as demonstrated by the comparison below.

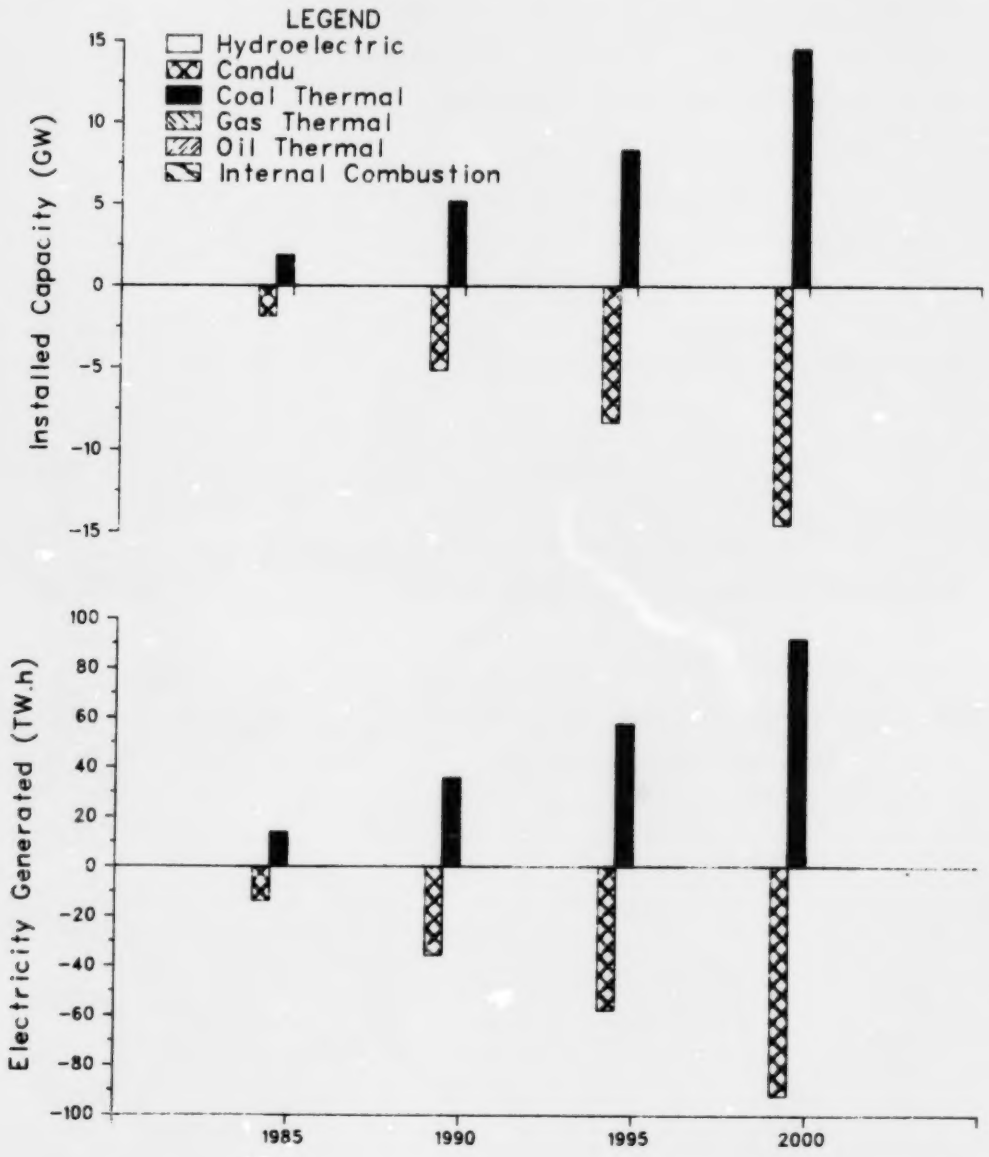
Revenue Requirements
(billions of current dollars)

	1980	1990	2000
Base Case	0.86	3.15	12.46
Type 6 Sensitivity	0.86	3.70	14.37

It may be that with several different coal-fired types of generation (base versus intermediate) available to the model, the consequences of a nuclear moratorium would be more realistically portrayed. For example, a region like Ontario would examine more than one coal-fired alternative (bituminous, subbituminous, lignite) in response to a nuclear moratorium.

FIGURE 37: Summary of Sensitivity Results – Type 6
(bar graphs indicate level differences from base case)

	1985	1990	1995	2000
Electric Energy Demanded (TW.h)	49	65	87	117
Peak Power Demand (GW)	9	12	16	21
Cost of Electricity (mills/kW.h)	46	57	81	123
Reserves Based on Installed Capacity (%)	23	22	20	19



3.2.7 Type 7, Increased Lead Times

Stimulus:

In this case, the amount of time necessary to bring coal and nuclear types of new capacity on line was increased. Such a scenario could be caused by increased regulation (longer environmental/economic impact hearings) or construction capital or labour shortages.

It was specified that the major generation alternatives (coal and CANDU) were 'in construction' for an additional two years. Thus, the original construction expenditure profile for those plant types was lagged by two years, indicative of a situation where actual construction was delayed by that time period.

Impact:

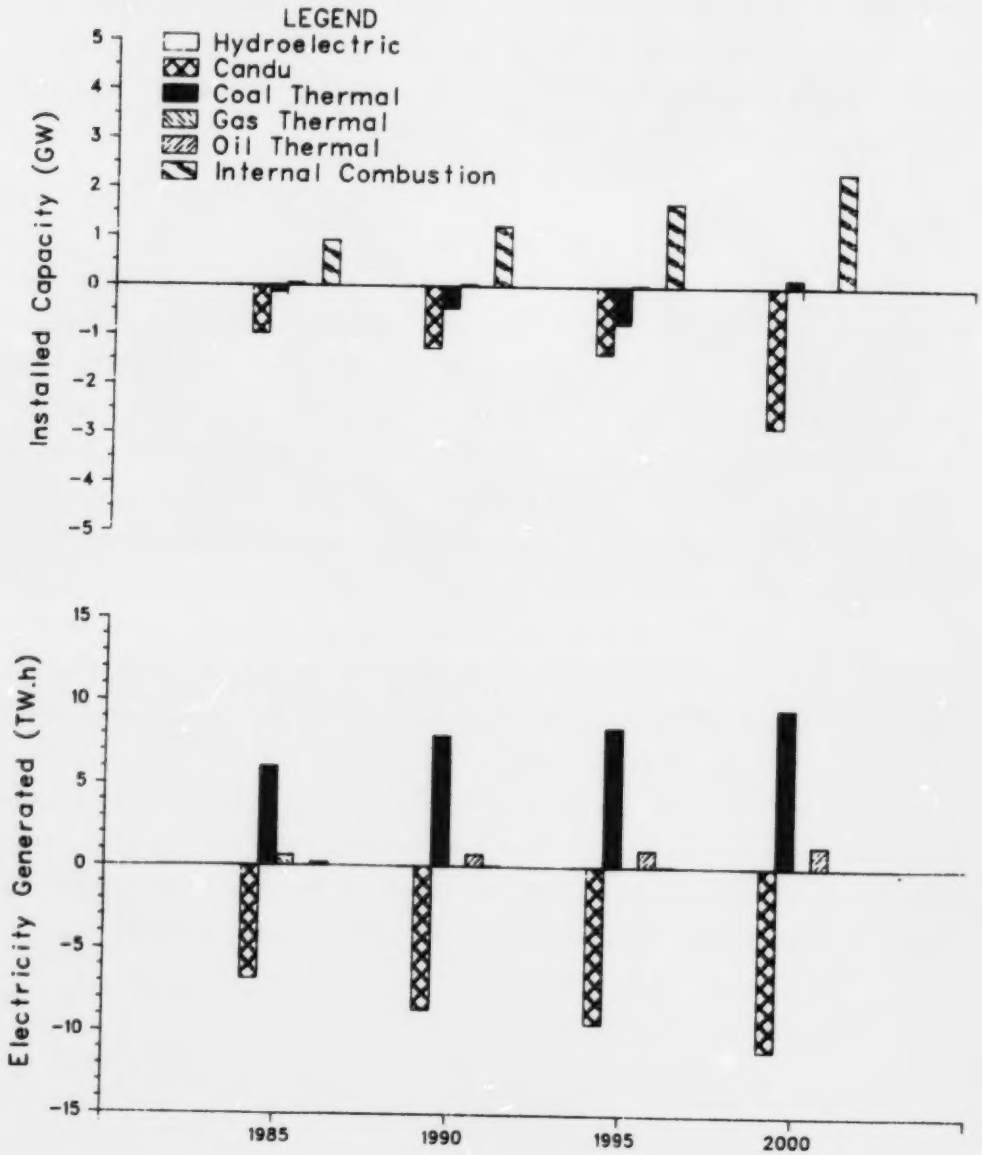
The major consequence in this simulation is that nuclear units are not brought in-service until 1984 (base case was 1982). This factor combined with the longer lead time for coal-fired units resulted in internal combustion units 'making up' the difference, as may be observed from Figure 3.8. The five year difference in construction times between coal or nuclear plants and peaking capacity results in the commitment to construct considerably more of the latter type of capacity to keep reserve levels up.

The two-year postponement of nuclear appearing in this hypothetical system also meant that the other plant types, specifically the next lowest operating cost alternative--coal--had to be run considerably more than in the base case.

The result in the year 2000 is slightly less capacity meeting the same energy demand. The implication of the largely internal combustion versus nuclear capacity tradeoff and the higher usage factor for all generating stations is a slightly lower average bulk power cost.

FIGURE 3.8 Summary of Sensitivity Results – Type 7.
(bar graphs indicate level differences from base case)

	1985	1990	1995	2000
Electric Energy Demanded (TW.h)	49	65	87	117
Peak Power Demand (GW)	9	12	16	21
Cost of Electricity (mills/kW.h)	32	47	70	105
Reserves Based on Installed Capacity (%)	21	18	18	18



3.3 General Applicability

Overall, we found the REM projections to react as expected to the changes imposed. We emphasize though that the preceding examples indicate only a few of the many situations to which REM is applicable. We conclude with a list of potential policy applications.[3]

- Changes in factors affecting electricity demand growth paths
  - economic/demographic trends
  - conservation policies
- Load management
  - peak load pricing
  - co-generation
  - seasonal pricing
- Impacts of changes in cost factors
  - capital costs for new plants
  - fuel prices
  - wage rates
  - taxes (possibly a Btu tax)
- Changes in resource supply conditions
  - resource constraints
  - increasing cost supply schedules
- Costs of financing
- Industry responses to capital 'shortage'
  - government financing
  - less capital-intensive technologies
  - reduce growth
  - reduction in plant reserve margin
- Regulatory policies
  - regulated rate of return
  - inclusion of work in progress in rate base
  - exclusion of non-economic plants from rate base
  - regulatory lag
- Alternative lead times for capacity expansion
- Environmental constraints
  - siting restrictions
  - capital equipment requirements
  - increased operating costs
- Technology assessment
  - advanced generation technologies: co-generation
    fuel conversion
  - nuclear
  - storage
  - transmission and distribution

Footnotes

[1]In reality, the move from intermediate through peaking to reserve status takes place very quickly. It is uneconomic and, in some cases, almost physically impossible to run oil-fired steam capacity as peaking capacity.

[2]If we presume that 'baseload' can be defined as 50 percent of the annual peak, then baseload generation in 1995 must be at least (9.98 GW x 0.5 x 8,760 hours = 43.7 TW.h.)
Nuclear plus hydro generate 56 TW.h in 1990.

[3]Load factor is defined as the ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period.

[4]This list has been taken almost verbatim from MIT Model Assessment Group, Table 3.23, p. 3.140.

CHAPTER 4

PROPOSED DIRECTIONS OF FUTURE RESEARCH

With respect to our overall objective of attaining a capability to conduct policy analysis on the Canadian electricity sector, several obstacles remain. These concern both the data requirements and the modelling tool itself.

The data requirements of REM are large and by their nature (regional and equipment specific) are not readily obtainable. Ideally such a data collection effort should proceed with the co-operation of the utilities themselves. This task may indeed have externalities:

- to indicate areas where the industry could benefit from the standardization of data reporting across regions
- to provide an informal liaison between system planners with respect to national policy orientated modelling (recognizing that each individual utility is part of a larger entity with influences flowing in both directions).

Regarding further model modification, an array of possibilities exist. Indicated below are broad areas of REM to which research should be devoted before it may legitimately be applied to Canada. These fall into the short and long term categories.

4.1 Prospective Modifications: Short Run

Problem Area: The present structure of REM is quite rigidly set up to have one plant type for each fuel type. For example, there is only one kind of coal-fired power plant with a given heat rate, operating cost, forced outage rate, and so on. REM, however, requires this single plant type to serve two distinctly different purposes. First, the unit has a function as the state-of-the-art new plant that is offered to the generation expansion model, but then the same plant type is used as the national average plant for simulating the operation of the system. Since the national average coal plant is of much older vintage than the national average nuclear there seems to be a clear bias toward choosing the latter in system planning.

Proposed Solution: It would be desirable to expand the number of technologies to have not just one but several options for each plant type. The inclusion of technologically more efficient thermal units in the expansion planning module will create a more realistic portrayal of generation plant options currently available to the system planner. Ideally, for adequate technology assessment, each type of plant projected to be commercially viable in the next twenty-five years ought to be represented in the system.

Problem Area: The present handling of prospective hydro capacity is inadequate, although it is understandable in the U.S. where it contributes a small and declining proportion of total generation. The level of future hydro capacity is now determined via an exogenously specified schedule.

Proposed Solution: Recognizing that the economics of hydro generation are site specific, each option should enter into the planning 'candidate list' on its own merits as an additional (once only) plant type. Likewise, several alternatives at an individual site (low, medium and high head, for example) could be incorporated regionally.

Problem Area: With respect to the derivation of electricity demands, it would be more consistent to have an imbedded demand submodel that adequately reflects the Canadian context.

Proposed Solution: Data collection is currently underway to permit the re-specification and re-estimation of a demand submodel similar to the one contained within the 'original' REM. This is also the case for the transmission and distribution module.

The complete application of REM to Canada is not a short term project. We envision successive applications, each more comprehensive, as REM undergoes further adaption and specification.

4.2 Prospective Modifications: Long Run

- As a check on the validity of the REM results, we would like to run a more sophisticated, and utility-specific, systems simulator model with data for one region. To this end we have acquired the WASP model and are currently developing the expertise to implement it.[1]

- To properly examine the implications of a uranium price change, or physical shortage for instance, a detailed CANDU fuel cycle module must interface with the REM supply submodel. We will pursue the possibility of adapting an existing nuclear process model for these purposes.[2]

- Interregional transfers of electricity cannot explicitly be addressed within the present configuration of REM.[3] We could approach this problem in two different ways. An 'export' and 'import' capacity type (with associated constraints and costs) could be added to each region, or alternatively, optimal system size could be investigated by changing the size of the regions modelled. For example, it would be possible to model two adjacent regions as one with appropriate operating and planning constraints.

- Eventually we would like to add substantially to the pricing component of the model. A methodology with associated computer implementation has been developed at CERI to estimate customer reactions to a change in electricity rate structures.[4] The model consists of two major components which quantify changes in energy sales and hour-by-hour loads due to any type of rate structure change. The results are generated for each year of the planning horizon. We would hope to integrate this rate impact model with REM in order to provide a supply side feedback for the investigation of time of day pricing, load management and related issues. This would involve the introduction to REM of seasonal load curves and an increased number of customer classes.

- Ultimately, we envision REM interacting with a comprehensive Macro/Energy model. REM would provide the necessary detail usually missing in the electricity sector of such models.[5]

Footnotes

[1]The Wien Automatic System Planning (WASP) model was originally developed by the Tennessee Valley Authority and the Oak Ridge Nuclear Laboratory for the International Atomic Energy Agency. The program uses a probabilistic approach to simulate system operation and a dynamic methodology to evaluate and compare alternatives. See Chase and Whalen for more detail.

[2]Similarly, work is underway in the U.S. (Martin Zimmerman, MIT) aimed at incorporating specific regional coal supply functions into REM.

[3]Specific reference to interregional transmission, and an alternative supply-side methodology, is provided in Choudhury (see Bibliography).

[4]G. J. Protti and R. N. McRae, The Impact of Rate Structure Change of Electricity Demand: A Case Study of Calgary Power Limited, Study No. 10, Canadian Energy Research Institute, 1980.

[5]Integration of REM with an aggregate model of the U.S. economy is being undertaken (Dale Jorgenson, Harvard).

APPENDIX A

APPLICATIONS AND REVIEWS OF THE REGIONALIZED ELECTRICITY MODEL

The Regionalized Electricity Model was constructed during the early seventies. Policy analysis with the model commenced in earnest in 1975 and the first independent review of the model was completed in 1976.

1975

Regulatory and Tax Alternatives and the Financing of Electricity Supply (Kamat, Baughman and Joskow)[1]

REM was utilized in this case to support the claim that the U.S. electric utility industry would face serious capital shortages over the 1975-1995 time period unless a higher rate of return on equity and/or the inclusion of a portion of 'construction work in progress' in the rate base were allowed.

1976

The Future of the U.S. Nuclear Industry (Joskow and Baughman)[2]

The paper examined (using REM) the demands for nuclear reactors, raw uranium and fuel cycle requirements by the U.S. electric utility industry over the next twenty years, under a number of different assumptions.

Energy System Modeling and Forecasting
(Hoffman and Wood)[3]

This review article contrasted the REM engineering process approach to modelling electricity supply with an econometric approach (Griffin).[4] The superiority of the former for policy analysis is evident because REM is more detailed and realistic in areas such as generating plant types and technological factors influencing electricity generation.

Fuel Utilization by the Electric Utility Industry in the United States 1975-1995 (Joskow and Rozanski)[5]

In this application of REM, the effects of changes in the estimated costs of coal and uranium on electricity demand and fuel utilization were compared relative to a REM base case and other published projections.

1977

The Future Outlook for U.S. Electricity Supply and Demand
(Baughman and Joskow)[6]

In this paper, REM was used to assess the prospects of the United States electric utility industry through the 1977 to 1995 period. A set of supply and demand projections derived from REM were compared and contrasted with other publicly available forecasts. Future uncertainties discussed include problems in capital attraction necessary for financing expansion, difficulties in closing the fuel cycle and the decline in average-to-peak load ratios.

Effects of a Nuclear Moratorium on Regional Electricity Prices and Fuel Consumption by the Electric Utility Industry
(Joskow and Rozanski)[7]

This analysis involved the application of REM to one of the major policy dilemmas in the United States.

1978

Evaluation of System Expansion and Electricity Supply Model Used in REM (Jenkins, TVA)[8]

This report (prepared by a system planner at the Tennessee Valley Authority) found REM to be inappropriate for use by individual electric utilities for system planning or operation purposes. This is not surprising given that REM was developed for broad policy analysis.

A Survey of Econometric Models of the Supply and Cost Structure of Electricity (Cowing and Smith)[9]

In the section reviewing models of the entire electric power industry, the authors compared four models: Griffin (1974), REM, the supply of electricity component of the Federal Energy Administration PIES (Project Independence Evaluation System) model and the electricity portion of the Hudson-Jorgenson macroeconometric model (which outlines the relationships between the energy sectors and the economy as a whole). The authors reached the following conclusions in their analysis.

- "Griffin's specification of the production process is overly simplistic." (p. 179)
- "A brief comparison of the Griffin and Baughman-Joskow (REM) models suggests that the latter is relatively rich in its technical detail, allowing for eight different types of equipment to be selected, identifying individual energy conversion efficiencies for each and providing a more reasonable specification of the relationship between peak and total demand." (p. 183)
- The authors pointed out that REM produces financial and technical distortions because it aggregates across many utilities in one region. However, they stated that "despite these limitations, the Baughman-Joskow (REM) model does offer a flexible simulation tool capable of analyzing a much wider array of technical and economic alternatives than the Griffin model."[10] (p. 184)

- The PIES model was only reviewed briefly, since the available documentation was rather limited. The author found that PIES was "quite similar" to REM and "can be considered to have a similar theoretical rationale." (p. 184-185)

- "It (PIES) appears to simplify the more realistic lead-time mechanism of the REM structure. The same limitations raised with the Baughman-Joskow model will hold for the PIES structure. They are likely to be more relevant for the PIES case, since the model does not separate:

  (a) outage rates by type of equipment
  (b) the investment planning division's forecast of demand and actual demand
  (c) the pricing and production division
  (d) the costs of servicing different customer classes

  The linear programming approach (of PIES) does, in principal, have a significant advantage over the REM parametric simulation method in that is permits account to be taken of more of the technical parameters of each type of generating equipment. Unfortunately, without explicit knowledge of the technology matrix used in the model, we (Cowing and Smith) cannot assess whether the model fully exploits its potential." (p. 185-186)

- "The Hudson and Jorgenson approach contrasts rather dramatically with the previous supply models in that it relies on neoclassical theory and perfectly functioning markets for 'simple' economies to derive supply responses for the aggregate U.S. economy and never considers aggregation problems. It ignores the problems of capacity planning, composition of demand by peak, cycling and base, and assumes that all electricity is supplied as if it came from a production possibility frontier defined with nine outputs. It is clear that this model has little to offer for detailed analysis of the electricity industry." (p. 187)

- "On the basis of the information available, the Baughman-Joskow model appears to offer the most detailed view of the industry--allowing for a variety of equipment types with their associated heat rates and patterns of outages." (p. 187-188)

Independent Assessment of Energy Policy Models:
Two Case Studies (The MIT Model Assessment Group)[11]

This study is a pioneering effort designed to set standards for future model assessments. Therein, REM was subjected to two assessment procedures. The first was an overview assessment which was defined to encompass review and evaluation of model documentation including model descriptions, results, and applications. The second assessment technique was 'in-depth'. It included actual 'hands-on' examination and operation of the model and the associated data base. The study team's conclusions with regard to REM were as follows:

- General Assessment - REM represents an innovative and generally successful effort to model the demand, supply, and financial/regulatory components of the electric power sector. The most innovative aspect of the model is the consistent integration of these components, a characteristic unique to this model so far as we are aware. The modular organization of the model facilitates use in policy analyses and in general contributes to flexibility and to potential for extension and modification for new policy applications.

- Documentation - REM documentation is superior to that of most similar models with which we are familiar.

- Usability - In general, REM is useful for a wide range of policy analysis applications of interest and importance to the electric power industry. However, the potential user should be cautioned that the model has not been implemented in a manner that facilitates use by those unfamiliar with its intricacies and peculiarities.

1979

Review of Large-Scale Energy Models
(Charles River Associates Inc.)[12]

This major review work conducted for the Electric Power Research Institute analyzed over a dozen major models ranging from macroeconomic-energy models to industry models such as REM. The review's major conclusions with regard to REM were as follows:

- The REM electricity supply specification and results can be compared with those of other models: less sophisticated electricity supply models, such as PIES or DESOM[13] and much more complex models such as the detailed similation models employed for power system planning by electric utilities and power pools (for example, WASP).[14] This feature of the Baughman-Joskow model makes it testable and readily understandable.

- The REM specification of existing electricity generation and capacity expansion is richer and more flexible than similar specifications in such models as DESOM and PIES.

- From the standpoint of its specification and the highly practical focus of its design, we find the Baughman-Joskow model to be one of the most promising models of those reviewed. We believe EPRI should become familiar with it, subject it to extensive testing, and explore extensions, modifications, and incorporation of some of its features into improved models of electricity supply, rates and financing. Direct integration with EPRI's forthcoming coal supply model systems should also be explored.

Electric Power in the United States
(Baughman, Joskow and Kamat)[15]

This book describes REM, outlines recent improvements to the model and analyzes various policy issues through model simulation. The issues examined are regional fuel utilization by the electric utility industry, an analysis of the U.S. nuclear industry, alternative air quality restrictions, peak load pricing, decreased nuclear lead times, a nuclear moratorium, high capital costs, the reprocessing and plutonium recycle and financing the future growth of the electric power industry.

The review articles by Cowing and Smith, the MIT Model Assessment Group and that of Charles River Associates were especially instrumental in our selection of the Regionalized Electricity Model as the 'best available' computer methodology for electricity-related policy analysis. It is noteworthy that EPRI has acquired REM and is utilizing it in a comprehensive research program.

Our summary of model reviews did not include surveys which simply list and describe various modelling approaches. Since such surveys do not assess models but rather simply summarize model documentation or descriptions, they were of minimal assistance. [16]

Footnotes

[1]Dilip P. Kamat, Martin L. Baughman, and Paul L. Joskow, "Regulatory and Tax Alternatives and the Financing of Electricity Supply," (Austin, Texas: Center for Energy Studies, The University of Texas, September, 1975), Research Report RR-7.

[2]Paul L. Joskow and Martin L. Baughman, "The Future of the U.S. Nuclear Energy Industry," (Cambridge, Mass.: Economics Department, Massachusetts Institute of Technology, April, 1975), Working Paper No. 155.

[3]K. C. Hoffman and D. O. Wood, "Energy System Modeling and Forecasting," Annual Review of Energy 1 (1976): pp. 423-453.

[4]J. M. Griffin, "The Effects of Higher Prices on Electricity Consumption," Bell Journal of Economics and Management Science 5 (1974): pp. 515-639.

[5]Paul L. Joskow and George Rozanski, "Fuel Utilization by the Electric Utility Industry in the United States 1975-1995," (Cambridge, Mass.: Energy Laboratory, Massachusetts Institute of Technology, May, 1976), Working Paper No. MIT-EL 76-006WP.

[6]Martin L. Baughman and Paul L. Joskow, "The Future Outlook for U.S. Electricity Supply and Demand," Proceedings of the IEEE 65 (April, 1977): pp. 549-561.

[7]Paul L. Joskow and George Rozanski, "Effects of a Nuclear Moratorium on Regional Electricity Prices and Fuel Consumption by the Electric Utility Industry," Land Economics 53 (February, 1977): pp. 23-42.

[8]Taber R. Jenkins, "Evaluation of System Expansion and Electricity Supply Model Used in the Baughman-Joskow Regional Electricity Model," (Chattanooga, Tennessee: Tennessee Valley Authority, February 28, 1978), prepared for Electric Power Research Institute Project RP 1015-2.

[9]T. G. Cowing and V. K. Smith, "A Survey of Econometric Models of the Supply and Cost Structure of Electricity," (Palo Alto, California: Electric Power Research Institute, March, 1978), EPRI EA-517-SR.

[10]The limitations that Cowing and Smith point out are not serious in the Canadian context as the model will be required to regionally aggregate over significantly fewer numbers of utilities (usually one utility is all that services one province) than in the U.S. case.

[11]Massachusetts Institute of Technology Assessment Group, Independent Assessment of Energy Policy Models: Two Case Studies (Cambridge, Mass.: Energy Laboratory in Association with Center for Computation Research in Economics and Management Science, MIT, May, 1978), report no. 78-011 prepared for Electric Power Research Institute.

[12]Charles River Associates Inc., Review of Large-Scale Energy Models (Palo Alto, California: Electric Power Research Institute, January, 1979) EPRI EA-968, Research Project 330-1.

[13]W. L. Marcuse, L. Bodin, E. Cherniavsky, and Y. Sanborn, "A Dynamic Time Dependent Model for the Analysis of Alternative Energy Policies," (Uphaven, New York: Brookhaven National Laboratory, undated), BNL #19406.

[14]D. B. Chase and M. Whalen, "WASP II - The Wien Automatic System Planning Package," paper presented to the Spring Meetings of the Canadian Electrical Association, Vancouver, British Columbia, March, 1979.

[15]Martin L. Baughman, Paul L. Joskow, and Dilip P. Kamat, Electric Power in the United States: Models and Policy Analysis (Cambridge, Mass.: The MIT Press, 1979).

[16]A. S. Manne, R. G. Richels, J. P. Weyant, "Energy Policy Modelling: A Survey," Operations Research 27 (Jan-Feb, 1979): p. 1-36.

APPENDIX B

INPUT DATA FOR BASE CASE SIMULATION
(All cost values are stated in current dollars)

The stipulated reserve margin for planning purposes is 20 percent.

TABLE B.1

PLANT CAPITAL COSTS
($/kW)

Year	Coal Thermal	Gas Thermal	Oil Thermal	Internal Combustion	Hydro Electric	PHWR (CANDU)
1977	300	200	250	170	500	650
1982	700	400	500	250	1,100	1,200
1987	1,000	600	800	350	1,400	1,500
1992	1,500	850	1,300	500	1,800	2,200
1997	2,200	1,250	2,100	750	2,900	3,200
2002	3,200	1,900	3,400	1,100	4,700	4,800

TABLE B.2

OPERATION AND MAINTENANCE COSTS
(mills/kW.h)

Year	Coal Thermal	Gas Thermal	Oil Thermal	Internal Combustion	Hydro Electric	PHWR (CANDU)
1977	0.80	0.60	0.70	3.34	0.20	1.10
1987	2.07	1.56	1.82	5.70	0.52	2.85
1997	5.38	4.04	4.71	9.74	1.35	7.40
2007	13.96	10.47	12.21	16.64	3.48	19.19

TABLE B.3

GENERATING PLANT HEAT RATES
(Btu/kW.h)

Year	Coal Thermal	Gas Thermal	Oil Thermal	Internal Combustion	Hydro Electric	PHWR (CANDU)
1977	10.0	10.9	11.0	15.0	10.0	11.5
1987	10.0	10.8	10.9	13.4	10.0	11.0
1997	9.5	10.7	10.8	12.9	10.0	10.6
2007	9.3	10.6	10.7	12.5	9.8	10.2

TABLE B.4

NATIONAL AVERAGE FUEL PRICES

Year	Coal ($/ton)	Gas (¢/mcf)	Uranium ($/kg)
1975	16	80	90
1980	27	210	110
1985	34	460	180
1990	43	650	260
1995	70	950	370
2000	113	1,400	500

TABLE B.5

MACROECONOMIC VARIABLES
(annual growth rates)

Population	0.75%	
Electricity Demand	6%	
Inflation	8.5%	(1975-1985)
	6.5%	(1986-2000)

TABLE B.6

FINANCIAL PARAMETERS

Regulated Return on Equity	14%
Cost of Debt	8.5%
Cost of Preferred Stock	8.7%
Debt Limit	55%
Preferred Stock Fraction	10%

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